Large General Service and Primary Metering Rates include provisions of alternate demand charges for customers meeting minimum load and load factor requirements.

The proposed rate design for each class generally follows the existing rate structure. The proposed rate design was developed to achieve a balance between Naperville's objectives to base the retail rates on the allocated cost of service, to minimize the impacts of rate changes on each group of customers, and to provide full recovery of the costs of providing service. The estimated total revenue based on the proposed rate design was $75,163,216, resulting in an overall decrease in revenues of 7.8 percent.

The cost-of-service analysis indicated that revenue decreases were appropriate for most rate classifications. Only the Primary Metering and Government classes were identified as requiring rate increases. Naperville decided to reduce the amount of the rate decrease proposed for the Residential Rate to offset the need for the increases to the rates for these two classes. However, the rate decrease proposed for the Residential class still exceeded 11 percent.

The rate design analysis also resulted in proposed cost recovery related to the electric service provided by Naperville to its three cogeneration customers. BMC recommends that Naperville implement individual monthly facilities reservation charges for each cogenerator. These charges were designed to provide full recovery of the transmission and distribution system facilities, the associated operations and maintenance costs, and administrative costs related to these customers being connected to the Naperville electric system. These facilities charges also include recovery of net margins allocated to the cogenerator customers. In addition, BMC proposes that all actual electric service taken by the cogenerators, regardless of whether identified as supplemental, maintenance, or backup, be billed at the wholesale power supply rates paid by Naperville for the corresponding month.

The study also included consideration of the potential for Naperville offering conjunctive billing to other customers having multiple demand meters/locations rather than billing the customers separately for each account or location. Conjunctive (aggregate) demand is the measurement of electrical demand that is the sum of the electrical demands recorded instantaneously (coincident) by all meters of a particular customer. Naperville's primary objective for considering implementation of conjunctive demand billing would be to enhance the services offered to its customers. Naperville concluded that it would offer conjunctive billing to customers meeting certain minimum service criteria. The criteria established were that a customer must maintain a minimum monthly maximum conjunctive demand of 500 kW with two meters or a minimum monthly maximum conjunctive demand of 300 kW with three or more meters.

However, since this would be an innovative approach to customer billing, implementation of conjunctive demand billing for any customer would be contingent on that customer agreeing to pay all costs associated with the required interval metering equipment.

SUMMARY AND RECOMMENDATIONS

BMC reached the following conclusions as a result of the analysis performed:

1. Naperville continues to generate high annual margins and positive financial results.
2. Naperville continues to experience high levels of growth in customers, energy sales, and revenues.
3. Naperville continues to obtain wholesale power at competitive costs.
4. Naperville continues to depreciate fixed assets at rates that appear reasonable compared to other public power systems.
5. Naperville now recognizes contributed capital as Other Operating Revenue in accordance with the requirements of GASB Statement No. 33.

BMC recommends the following:

1. Naperville should consider the proposed retail rates set forth in Part III for implementation, to be effective for fiscal year 2001-2002.
2. Naperville should eliminate the current General Service Electric Heating Rate and transfer the associated customers to the General Service Rate (would affect approximately 210 customers).
3. Naperville should eliminate the current Educational Institution Rate and the Religious Institution Rate and transfer the associated customers to the Large General Service Rate (would affect approximately 44 and 21 customers, respectively).
4. Naperville should eliminate the current Municipal Rate and transfer the associated customers to the Government Rate (would affect approximately 10 customers).
5. Naperville should revise the minimum required load for eligibility for the Primary Metering High Load Factor Rate from 5000 kW to 3000 kW (would affect approximately 3 customers).
6. Naperville should evaluate and update the existing agreements with its customers owning cogeneration equipment.
7. Naperville should offer conjunctive billing for demand by customers having multiple locations.
8. Naperville should implement additional project numbers for capturing operating and maintenance expenses on a functional basis to enhance the cost information available for future rate studies.

9. Naperville should establish a periodic review for the assignment of non-residential customers to the appropriate rate classification.
10. Naperville should implement a load research program and install interval demand recording devices on a statistically valid sample of customers in all rate classes.
11. Naperville should continue to monitor developments relating to the restructuring of the electric utility industry on both national and state levels.

* * * * *

PART I – INTRODUCTION

PART I
INTRODUCTION

The City of Naperville, Illinois (the City) retained Burns & McDonnell Engineering Company (BMC) of Kansas City, Missouri, to prepare an Electric Rate Study for the electric utility of the Naperville Department of Public Utilities (Naperville). This report describes the electric cost-of-service analysis and retail rate design completed for Naperville.

BACKGROUND

Naperville's current electric rates were developed by BMC and documented in the Report on the Electric Cost-of-Service and Retail Rate Design Study, dated May 9, 1995. The rates designed in this 1995 study were implemented effective November 1, 1995. Since that time, Naperville's electric system load has increased substantially due not only to the rapid growth in the numbers of residential and small commercial customers, but also the additional loads associated with the Lucent Technologies Indian Hill Complex and the facilities expansions by other large general service customers.

In addition, the electric utility industry has continued to change significantly. In 1997, electric restructuring legislation was passed by the Illinois legislature that provided for retail electric choice for commercial and industrial consumers by the end of 2000 and for residential consumers by the end of 2002. Although the law provided an optional exemption to municipal utilities from being subject to competition, in the future, Naperville will experience increased pressure from its customers to provide reliable electric service at competitive prices.

Naperville purchases its system power requirements (other than small amounts of energy purchased from two cogenerators) from ComEd under a wholesale Electric Service Contract. This contract extends through May 2007 and contains specified charges for demand and energy that increase for each remaining year of the agreement. However, the Electric Service Contract provides that Naperville will pay to ComEd each month the lesser of the billing amount determined under the Contract rate or 95 percent of the billing amount determined based on ComEd's current Large General Service Rate (Rate 6L).

This Electric Rate Study was initiated by the City primarily to assess the potential impacts of the issues described above on Naperville's revenues and costs, its overall financial position, and its retail electric rates over the next several years.

EXISTING ELECTRIC RATE STRUCTURE

Naperville currently bills its electric customers based on its retail rate schedules, which became effective November 1, 1995 (except as noted). The rate schedule classifications are as follows:

- Residential
- Residential Electric Heating
- General Service
- General Service Electric Heating
- Large General Service
- Large General Service Amended (effective July 21, 1998)
- Primary Metering
- Primary Metering Amended (effective July 21, 1998)
- Primary Metering Time-of-Use
- Transmission Metering
- Government
- Municipal
- Municipal Utility Pumping
- Educational Institution
- Religious Institution
- Athletic Field Lighting
- Street Lighting
- Contract Outdoor Lighting
- Metered Outdoor Lighting
- Traffic Lighting

The Residential, Residential Heating, General Service, General Service Heating, Metered Outdoor Lighting, and Traffic Lighting rates consist of monthly customer charges and energy charges per kilowatt-hour used. The Street Lighting and Contract Outdoor Lighting rates are flat monthly charges per lamp based on size. The rate schedules applicable to the other classifications include demand charges per kilowatt of maximum monthly demand in addition to monthly customer charges and energy charges.

SCOPE OF STUDY

Naperville's objectives for this rate study included:

- To update retail rates based on changing costs of providing service.
- To ensure full recovery of costs of providing service.
- To adopt current leading edge practices in design of rate alternatives.
- To build and improve upon the rate enhancements achieved with the last retail rate change implemented November 1, 1995.
- To consider the results of previous studies related to the rates charged to Lucent Technologies and to customers having cogeneration facilities.

Naperville and BMC agreed to consider several specific issues related to Naperville's costs of providing service and its electric rates as part of the cost-of-service analysis and rate design. These include:

- Unbundling of the costs of providing separate functional services
- Appropriateness of depreciation expense rates
- Clarification of definitions for rate classifications
- Implementation of conjunctive billing for demand (sum of customer's instantaneous demands recorded at multiple metering locations).
- Approach to costing of various lighting rate classifications
- Interpretation of load profile data
- Appropriateness of primary metering rate
- Design of time-of-use rates

Each of these areas was incorporated into BMC's analysis presented in this report.

METHOD OF ANALYSIS

The cost-of-service analysis and rate design study performed by BMC consisted of several steps. The cost-of-service analysis included the development of the adjusted annual revenue requirement based on operating results for a historical test year period and for three future years, as projected by BMC. This was followed by the assignment, or unbundling, of the various costs and margins included in the adjusted annual revenue requirement to the electric utility functional services (i.e. power supply, distribution, customer service, etc.). These unbundled cost components of the adjusted annual revenue requirement were then allocated to Naperville's various electric rate classifications. The resulting allocated cost of service for each rate classification was compared to the adjusted annual service revenues for each class to assess the projected cost recovery provided by the existing retail rates. These steps and the corresponding results are explained in Part II of this report.

The results of the cost-of-service analysis provided Naperville with a basis for considering whether revisions to its electric service rates were necessary. Part III of this report discusses the implications of the cost-of-service results on Naperville's current electric rates and describes the proposed modifications to those retail rates. Comparisons of sample monthly bills based on the current and proposed rates for each customer classification are also presented.

The Summary and Recommendations section, included as Part IV of this report, summarizes BMC's findings from the cost-of-service analysis and rate design study and presents our recommendations for Naperville and the City.

Throughout this report, references are made to various Figures that illustrate key concepts and Tables that detail specific aspects of the analyses completed. These Figures and Tables are included in Appendices A and B, respectively, at the back of the report.

SOURCES OF DATA

Naperville and the City's Finance Department provided the information used in the preparation of this cost-of-service analysis and rate design study. This included various analyses, computer-generated information and reports, audited financial reports, and other financial and statistical information, as well as other documents such as power bills, debt service schedules, and current retail electric rate schedules. Naperville also provided input to key assumptions regarding expected future levels of revenue, sales, and expenditures.

In the preparation of this report, BMC used the information provided by Naperville to make certain assumptions with respect to conditions that may exist in the future. While BMC believes the assumptions made are reasonable for the purposes of this report, we make no representation that the conditions assumed will occur. BMC has also relied on the information provided to us without independent verification and cannot guarantee its accuracy or completeness. Therefore, to the extent that actual future conditions differ from those assumed in this study or from the information provided to us, the actual results may vary from those projected.

PART II – COST-OF-SERVICE ANALYSIS

PART II
COST-OF-SERVICE ANALYSIS

OVERVIEW

BMC prepared an electric unbundled, allocated cost-of-service analysis for Naperville. This analysis resulted in comparisons of the revenue requirement allocated to each rate classification to the revenues provided by Naperville's current retail electric rates. The analysis was developed within BMC's Unbundle™ software, a proprietary cost-of-service model for electric utilities.

The cost-of-service analysis prepared for Naperville's electric utility included the development of the estimated annual revenue requirement, the unbundling of the total revenue requirement among specific services, and the allocation of the costs of providing those specific services to each of the rate classifications served by Naperville. The revenue requirement allocated to each rate class was then compared to the estimated annual revenues based on each class's current retail rates.

The results of this analysis provided an indication as to the need for rate changes (increases or decreases) for each rate classification. The details of the allocated, unbundled revenue requirement of each classification served as a basis for the development of revised retail rates.

Figure 1, included in Appendix A, presents a flow diagram to illustrate the process for the development of the cost-of-service analysis as described above.

ADJUSTED ANNUAL REVENUE REQUIREMENT

BMC developed the adjusted annual revenue requirement to be used as the basis for Naperville's allocated, unbundled cost-of-service analysis. This adjusted annual revenue requirement was determined by calculating three-year averages of projections for each of the various component revenues and expenses for Naperville's fiscal years (FY) 2002 through 2004. The adjusted annual revenue requirement and cost-of-service analysis were based on three-year averages of projected revenues and expenses for Naperville such that proposed retail electric rates resulting from this study should provide sufficient revenues for at least the next three years.

In the development of the projections of revenue and expenses for FY2002 through FY2004, BMC began with the financial operating results of Naperville for the fiscal year ended April 30, 1999 (FY1999). However, since the accounting records for Naperville are maintained in the City's governmental accounting system, the account structure and account numbers are not defined in accordance with the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). As a result, in preparation for this rate study, the staff of the City's Finance Department spent a substantial amount of time translating the available detail account data for FY1999 to the FERC System of Accounts.

BMC believes that the current accounting software used by the City has the capacity and flexibility that would allow the FERC system of accounts to be implemented for the electric utility. Naperville should consider implementing additional project numbers for capturing operating and maintenance expenses on a functional basis. This would better support the unbundling analysis (discussed later in this section) of the annual revenue requirement and would facilitate more timely data collection for updates to the cost-of-service analysis for future rate studies. It also is becoming increasingly more important for Naperville to be able to analyze and better manage its costs, in detail, and to readily benchmark its operating performance against other utilities. BMC reiterates its recommendation that the City and Naperville give this issue serious consideration.

Adjusted Statement of Income

Table 1, included in Appendix B, presents an Adjusted Statement of Income for Naperville that summarizes the development of the adjusted annual revenue requirement. As was mentioned, the analysis of the annual revenue requirement was based on Naperville's financial and statistical results for FY1999. The audited Statement of Income for FY1999 is shown in the first column of Table 1, which indicates that Total Net Margins for the year were $3,389,387. Based on Naperville's debt service for FY1999, interest coverage and debt service coverage ratios were 3.98 and 3.48 times, respectively. With total rate base as of April 30, 1999 of slightly greater than $125.4 million, Naperville earned a return on rate base of 2.70 percent during FY1999. X

BMC developed projections for each line item of Naperville's revenues and expenses, as well as rate base, for each of the fiscal years ended April 30, 2002, 2003, and 2004. The three-year averages of these projections are shown in the center column of Table 1, titled "Preliminary Adjusted 3-Year Average." The difference between the three-year average and the FY1999 amount for each line item is shown as the adjustment amount in the second column of Table 1. Based on the projected three-year average results, Naperville's net margins would grow to $8,111,650, the interest coverage ratio would increase to 10.41 times, and the debt service coverage would rise to 5.57 times. Naperville's return on rate base would also increase to a rate of 4.42 percent.

In order to finalize the adjustments to determine the annual revenue requirement for the cost-of-service analysis, these projected three-year average results were compared to Naperville's financial objectives. For the previous electric rate study completed in 1995, a target interest coverage level of 3.00 was established. For consistency, the same financial performance target was assumed for this analysis. On Table 1, the 'Required Revenue Adjustment' column shows a decrease adjustment to Electric Rate Revenue of $6,386,879, which was incorporated into the "Final Adjusted 3-Year Average" in the last column. With this adjustment, the projected interest coverage ratio was shown to drop to 3.00 times. As a result, the debt service coverage ratio would fall back to 3.38 times and the rate of return on rate base would decrease to 0.94 percent.

Summary explanations of the development of the projected revenues and expenses and their incorporation into the adjusted annual revenue requirement as presented on Table 1 are provided below.

Projections of Revenues and Expenses

For major items included on Table 1, such as Rate Revenues, Other Operating Revenues, Cost of Purchased Power, Depreciation Expense, and Interest on Long-Term Debt, projections were developed for each fiscal year through FY2004 based on Naperville's load forecast, budget data, debt amortization schedule, and specific assumptions about future conditions. All other line items of revenue and expense were either held constant at FY1999 levels or were escalated at a compounded average rate of growth of 6.7 percent per year. BMC calculated this composite annual growth rate based on expense level changes anticipated in the FY2004 Budget as compared to the FY2001 Budget for the Administration, Support Services, Electrical Engineering, Distribution, and Supply and Control Divisions. The budget figures were obtained from the Five Year Financial Plan FY2001-2006 for the Electric Utility Fund. Descriptions of the forecasts developed for the major items follow.

Rate Revenue Forecast: Table 2 presents the development of BMC's projections of Naperville's three-year average energy sales and utility service revenues for FY2002 through FY2004, as reflected on Table 1. These projections were developed for the rate classifications listed on Table 2. The determination of this list of rate classes is discussed later in the Revenue Requirement Allocation section.

The actual energy sales and revenues for FY1999 are shown in the first two columns on Table 2. At the bottom of the energy column for FY1999 is a comparison of Naperville's total energy requirement to the total energy sales, resulting in 'Unaccounted-for energy' (losses plus unmetered energy, such as street lighting) of 4.11 percent. Naperville provided estimates of its annual wholesale bulk power purchases for

FY2002 through FY2004. Projections of total annual sales for each fiscal year were determined by applying the unaccounted for energy factor Naperville experienced in FY1999 to the corresponding total projected energy purchases. Total annual sales were projected to grow from 1,012,523 megawatt-hours (MWh) in FY1999 to 1,383,866 MWh in FY2004.

The total projected energy sales for each fiscal year were allocated among the rate classifications. Energy sales associated with specific load additions for several large primary metered and large general service customers, i.e. Lucent Technologies, Tell Labs, and Edward Hospital, were factored into the projections for the respective rate classes. Otherwise, the sales to the rate classes other than the residential and general service classes were projected to remain at FY1999 levels. The remainder of anticipated sales increases for each fiscal year, beyond the specific load additions, were allocated among the Residential, Residential Electric Heating, General Service < 50 kW, and Large General Service rate classifications. This allocation was based on the ratios of each class's sales to the combined sales in FY1999.

Once energy sales to each rate classification were developed for FY2002 through FY2004, annual rate revenues were estimated. The average revenue per MWh rate was calculated for each rate classification based on actual FY1999 sales and revenues as adjusted for projected load increases. The average rate determined for each class was multiplied by the projected energy sales of the corresponding class to forecast the annual revenues for each fiscal year.

Table 2 presents the average annual sales and revenues for each rate class for the three-year period FY2002 through FY2004. Energy sales were projected to average 1,315,096 MWH and to generate average revenues of $81,551,039.

Other Service and Operating Revenues Forecast: Below the class sales and revenue forecast on Table 2 are Naperville's projected non-rate revenues. The Other Service Revenues and Other Revenues include income from various equipment charges, temporary service fees, late payment charges, and other intergovernmental charges. These revenues were assumed to generally remain at FY1999 levels.

However, a significant increase was forecast beginning in FY2002 for Other Revenue. To conform to Governmental Accounting Standards Board Statement No. 33 (GASB 33), issued in December 1998, the City changed its method of recognizing developer's contributions for the years after fiscal 1999. In prior years, contributions were recognized as contributed capital; for years after 1999, they were classified as other revenue. The amount of the increase is $4,303,699. This includes an amount of $1,803,699 in calculated annual depreciation on the portion of assets financed by contributed capital in fiscal years through FY1999. The remaining $2,500,000 is the average amount of additional contributed capital estimated for FY2002 through FY2004. Since the Other Revenue category is deducted from the cost-of-service in determining the annual revenue requirement, this change had a significant impact on the adjusted annual revenue requirement, as will be illustrated later.

The projected three-year averages for Other Service Revenues and Other Revenues, as shown on Table 2, were $342,800 and $4,905,040, respectively. This brought the projected average annual revenues for the period FY2002 through FY2004, including rate revenue, to a total of $86,798,879.

Purchased Power Expense Forecast: Table 3 provides a summary of the actual FY1999 and forecasted FY2002 through FY2004 purchase power expense for Naperville. The MW demand, on-peak and off-peak MWh energy, and related purchase costs and discounts are shown for each year for Naperville's full-requirements, wholesale power purchases from ComEd and for its purchases of as-available energy from two cogenerators, Nalco Chemical (Nalco) and BP (formerly Amoco). The summary purchased power expense data presented on Table 3 reflects the results of detailed projections of monthly power purchases and costs from ComEd, Nalco, and BP for FY2002 through FY2004. Discussion of how these detailed projections were developed follows.

As mentioned previously, Naperville provided projections of its annual wholesale peak demand and energy purchases from ComEd for FY2002 through FY2004. Monthly billing demands were estimated for each month during the forecasted years by multiplying the ratio of the billing demand for the corresponding month during FY2000 to the annual peak demand for FY2000 times the estimated peak demand for each year forecasted. The total energy forecast for each fiscal year was allocated between on-peak energy and off-peak energy based on the ratios of the combined FY1999 and FY2000 on-peak energy and off-peak energy purchased to the combined total energy for those same years. (The resulting ratios were 44.7 percent for on-peak energy and 55.3 percent for off-peak energy.) The ratios of the on-peak energy for each month during FY2000 to the annual on-peak energy for FY2000 were used to spread the allocated annual on-peak energy among the 12 months for FY2002 through FY2004. Similar calculations were used to project monthly off-peak energy for each year forecasted.

Naperville's purchases of energy from Nalco and BP are on an as-available basis. Therefore, there was no basis for projecting any changes in the amount of energy that will be purchased from these cogenerators.

BMC forecast monthly energy purchases from these two sources for FY2002 through FY2004 to be the same as during FY2000.

Estimated monthly power costs were calculated based on Naperville's current contractual arrangements with the three suppliers. Naperville's cost of power from ComEd is based on either the rate contained in its Electric Service Contract, dated December 1, 1986, as amended on August 2, 1994, or based on ComEd's current Large General Service tariff, Rate 6L, on file with the Illinois Commerce Commission. Naperville's amended contract with ComEd provides that Naperville's cost is the lower of the Contract rate or 95 percent of Rate 6L. Naperville's cost of power from ComEd was estimated for each month using the applicable rates defined in the Contract and at 95 percent of the current 6L rates to determine the lesser amount. For FY2002, the cost projections included seven months based on the Contract rate and five months based on Rate 6L. Projections for FY2003 and FY2004 included 11 and 12 months, respectively, based on Rate 6L.

The power purchased from the cogenerators each month is priced at the same rates at which Naperville purchases power from ComEd in the corresponding month. Based on the prior determination of the applicable rate between Naperville's Contract and ComEd's Rate 6L, the costs of the projected monthly energy purchases from Nalco and BP were estimated for each month of FY2002 through FY2004.

Table 3 presents the forecasted average MW demand, on-peak and off-peak MWh energy, and purchased power expenses for the three-year period FY2002 through FY2004. Total annual billing demand and energy purchased were projected to average 2,569.9 MW and 1,371,453 MWh, respectively, per year and total purchased power expense was estimated to average $58,515,475 per year.

Depreciation Expense Forecast: Table 4 details Naperville's end-of-year plant in service and annual depreciation expense for FY1999 and projected for FY2002 through FY2004. The plant balances and depreciation expenses are listed by FERC plant accounts within the functional categories of transmission, distribution, general and other plant.

The projected end-of-year plant in service balance for each year of the forecast was developed by adding to the FY1999 plant balances the actual or planned additions for each fiscal year. Naperville's 5-Year Capital Improvement Program details planned expenditures by year. Naperville expects that approximately 85 percent of planned capital additions each year will actually be completed. Therefore, the projected end-of-year plant balances incorporate the annual additions at 85 percent of the planned expenditures.

Naperville currently calculates annual depreciation expense by plant account based on depreciation rates that have been in use for a number of years. In the development of the depreciation expense forecast, BMC first compared Naperville's depreciation rates for each plant account to those of two other public power systems whose rates were readily available. Based on the comparison, the depreciation rates used by Naperville were found to be consistently in the same range of magnitude as those of the two utilities reviewed. Therefore, BMC concluded that Naperville's depreciation rates were reasonable and used them in the analysis.

To calculate projected total annual depreciation for FY2002 through FY2004, BMC utilized the composite depreciation rates for each plant account provided by Naperville, as discussed above. The respective depreciation rate for each account was applied to the average projected plant-in-service balance (sum of end-of-year balances for current and preceding years divided by two) for each year of the forecast to estimate the annual depreciation expense.

Table 4 shows the projected end-of-year plant in service and annual depreciation expense for the three-year period FY2002 through FY2004. Annual depreciation expense was projected to average $7,246,813.

Interest Expense Projection: Naperville's annual interest expense on long-term debt was projected for FY2002 through FY2004 based on current debt amortization schedules provided by Naperville for the four existing series of revenue bonds issued in 1991, 1992, 1996, and 1998. The 1991 series revenue bonds were scheduled to be retired during FY2001. Naperville does not anticipate issuing any new long-term debt in FY2001or during the forecast period. Therefore, the interest expense forecast includes the interest portion of the debt service on the three remaining series of revenue bonds. The average projected annual interest expense on long-term debt for the three-year period FY2002 through FY2004 was $862,385. As shown on Table 1, this is a decrease of $275,212 from The FY1999 interest expense.

Summary of Adjusted Annual Revenue Requirement

The adjusted annual cost of service consists of total operating expenses, including interest expenses, plus total net margins. The adjusted annual revenue requirement is equal to the annual cost of service minus other revenue. Figure 2, included in Appendix A, presents this formula and the calculation of Naperville's adjusted annual revenue requirement based on the average annual forecasted revenues and expenses for the three-year period FY2002 through FY2004, which are reflected in the final column of Table 1. Naperville's adjusted annual revenue requirement was forecast to be $75,164,160. Note that this is the amount of the final adjusted Electric Rate Revenue on Table 1. This reflects the overall decrease of $6,386,879 from the adjusted three-year average electric rate revenue also shown on Table 1.

COST-OF-SERVICE ANALYSIS

Unbundling of Adjusted Annual Revenue Requirement

Once the adjusted annual revenue requirement of Naperville was determined, its various components were unbundled by functional utility service. Currently, the electric service Naperville offers to its customers is sold as a bundled product. However, this bundled product actually involves the provision of multiple functional services. The restructuring of the electric utility industry and the potential development of retail competition to provide electric services to customers has given rise to the need for utilities such as Naperville to consider unbundling the costs of providing the individual component services making up this bundled product. Although not currently required by law to implement cost unbundling, Naperville will benefit from this separation of the costs of providing its services at a functional level. New information will be available to aid Naperville in the overall management of its costs and in communicating with its key customers regarding the costs of providing services to them. The unbundling of Naperville's costs also would facilitate future implementation of separate pricing of individual services, if desired.

Unbundled Services: The unbundling of the various components of Naperville's adjusted annual revenue requirement is summarized on Table 5, included in Appendix B. In analyzing the functional services Naperville currently provides to its utility customers, BMC and the Naperville staff identified 12 specific services in six functional service categories. These categories and services were defined as follows (abbreviations used on Table 5 are shown in parentheses):

- Power Supply
  - √ Demand, i.e. Capacity (kW)
  - √ Energy (kWh)
  - √ Transmission Access (ACC)
- System Control
  - √ System Dispatch and Control (SCNTL)

- Transmission
  - √ Transmission Delivery (TDEL)
- Distribution
  - √ Substation (SUBS)
  - √ Distribution Delivery – Primary (DIS-P)
  - √ Distribution Delivery – Secondary (DIS-S)
  - √ Metering (MTR)
- Customer
  - √ Billing & Collections (BL-CL)
  - √ Customer Service (CUST)
- Shared
  - √ Common (COM)

Assignment of Adjusted Annual Revenue Requirement: The final adjusted 3-year average amount for each account/element of other revenue, operating expense, net operating margins, and net non-operating margins were assigned to one or more of the unbundled services listed above. The unbundled assignment of each amount was based on the utilization of specific data to estimate the portions of each item attributable to the various functional services. The adjusted amount for each item was assigned using one of the following approaches:

- Direct assignment – to one or more specific functional services due to the nature of the account/element. For example, purchased power expenses were assigned to the Demand, Energy, and Transmission Access services based on actual amounts from power supplier invoices.
- Assumed percentage breakdown – based on estimated level of activities within the account/element. For example, 20 percent of expense amounts in supervision accounts and miscellaneous distribution expense accounts were assumed to relate to Substation service, with the remaining 80 percent relating to Distribution Delivery services.
- Application of statistical factors – representing the relative impacts of multiple functional services on specific costs. For example, amounts for various operations and maintenance expenses attributed to distribution lines were split between the Distribution Delivery – Primary and Distribution Delivery – Secondary services based on the miles of each type of line expressed as percentages of the total miles of distribution lines.

- Application of composite ratios – of the total assignments of a subset of other accounts/elements. For example, the ratios for each functional service of the subtotals of the assignments for all transmission, distribution, and customer operations and maintenance expenses were applied to administrative and general expenses to assign them to the same services.

The manner in which each account/element was assigned among the functional services varied based on the nature of the account. BMC developed the proposed unbundling of the accounts/elements of Naperville's adjusted annual revenue requirement based on its understanding of the types of costs included in each account. The actual assignment of each detail account/element is contained within the cost-of-service model prepared for Naperville.

In general, the assignment of the adjusted annual revenue requirement for Naperville was based on an underlying premise that in a restructured electric utility environment, recovery of the costs of power supply would be somewhat at risk. If retail competition were to be implemented for Naperville, and an existing customer were to choose to purchase its power from a different supplier, the fixed costs associated with the sales lost would not be recovered. Therefore, certain costs were assigned only to the non-power supply functional services.

The final adjusted functional operating expenses, interest and operating margins, non-operating margins, and other revenues shown in the last column on Table 1 were carried forward to Table 5. These amounts are followed by the summary of the assignments to each unbundled functional service. Table 5 shows that 77.8 percent (20.7 %-kW, plus 57.1 %-kWh) of Naperville's total adjusted annual revenue requirement was related to the power supply services.

Allocation of Adjusted Annual Revenue Requirement

Following the unbundling of the various components of the adjusted annual revenue requirement to the functional utility services, the unbundled revenue requirement was further allocated to Naperville's retail rate classifications. These allocations were developed to reflect the relative impact each rate class has had on the level of each component.

Rate Classifications: Naperville currently bills its customers based on its electric rate schedules, which became effective November 1, 1995. Two rate schedules were later amended as of July 21, 1998. The current rate classifications are as follows:

- Residential Rate
- Residential Electric Heating Rate
- General Service Rate (50 kW or less)
- General Service Electric Heating Rate
- Large General Service Rate (amended to add high load factor rate)
- Primary Metering Rate (amended to add high load factor rate)
- Primary Metering Time of Use Rate
- Transmission Metering Rate
- Government Rate
- Municipal Rate
- Municipal Utility Pumping Rate
- Educational Institution Rate
- Religious Institution Rate
- Athletic Field Lighting Rate
- Street Lighting Rate
- Contract Outdoor Lighting Rate
- Metered Outdoor Lighting Rate
- Traffic Lighting Rate

Naperville also provides electric service to three customers under separate individual contracts because they each own their own electric cogeneration equipment. These customers are Nalco, BP, and Northern Illinois Gas Company (Nicor).

Allocation Factors: BMC utilized detailed billing history data for FY 1999 and projections of future sales and loads provided by Naperville to develop a series of allocation factors. Based on statistical billing determinants, estimates of the contributions of each rate classification to Naperville's total annual system energy requirements, power supply billing demand, and noncoincident distribution system demand were developed. In addition, the numbers of customers on Naperville's system in total and in each rate category were also determined. Ratios were calculated of each class's contribution for each statistic to the corresponding total. These ratios were identified as the allocation factors used to allocate each unbundled component of the adjusted annual revenue requirement to Naperville's rate classes. The development of these allocation factors is detailed below.

Energy Allocation: An energy allocation factor was developed for use in the allocation of all energy-related expenses. Based on the billing data provided, BMC determined the historical energy sales to each of Naperville's rate classes/customers. The energy sales for each class were factored up to the system level. System losses were assumed to occur evenly between three stages: power supply delivery to transmission, from transmission voltage to primary distribution voltage, and from primary distribution voltage to secondary distribution voltage. Therefore, the rate classes receiving service at transmission voltage or primary voltage were assumed to not share in secondary distribution system losses. Similarly, the rate classes receiving service at transmission voltage were assumed to not share in the primary distribution losses. The related energy sales projections for each class were factored only for the appropriate shares of the transmission level and primary distribution level losses. The ratios of the resulting estimated contributions of each class to the total system energy requirements represented the energy allocation factors.

Demand Allocation: The determination of system demand contribution by each rate class was a more complex issue than the development of the energy allocation factors for two reasons. First, the normal operation of an electric utility does not require maintaining the same amount of demand-related data as it does energy-related data. Therefore, there was not an equal amount of data on which to base the analysis. The second reason is that there are a variety of methodologies that may be used in allocating the demand costs of an electric utility.

Power supply demand-related costs of Naperville were allocated using the 12 coincident peak responsibility (12-CP) method and all other demand-related costs were allocated using the non-coincident peak demand responsibility (NCP) method.

Naperville currently has hourly demand recorders installed on several of its largest customers (these customers were the ones separated for individual consideration in the analysis) and maximum demand meters installed on all of its non-residential customers. Ideally, hourly load profile information would be available for all of Naperville's customers, from which accurate coincident and non-coincident demands could be obtained. However, placing hourly load data recorders on every customer's premise would be cost prohibitive for Naperville. Naperville could install interval demand recorders on a sample group of customers within each rate classification. If data is compiled from a statistically valid sample of each classification, then load profile results obtained from each sample could be analyzed and applied to entire classes.

In the absence of actual load profile data for most of Naperville's rate classifications, for purposes of this study, demand contributions by class were estimated.

To allocate the demand-related power supply costs to the various customer classes of Naperville using the 12-CP method, estimates of each rate class's average contribution to Naperville's monthly power supply billing demand over a 12-month period were developed. Naperville is billed on a monthly basis for its wholesale purchases of power from ComEd. The demand component of each monthly bill is based on the average of the three highest half-hour interval demands recorded at the system level during the month (taken from three different days).

The dates and hours of the three highest demands used to determine Naperville's monthly billing demands were obtained from the monthly bills for FY1999. From the interval data for each of those customers with hourly demand recorders installed, the three demand readings coinciding to the dates and times of the system billing demands for each month were extracted and averaged. This resulted in determination of the contributions of these customers to the power supply billing demand for each month. The monthly contributions were averaged to calculate the demand contributions on an annual basis.

For those rate classes that were metered only for maximum demand, assumptions were made regarding the relationship between the maximum demand and the average demand coincident with the power supply billing demands. For some classes, coincidence factors were assumed based on various supporting data available or on experience. For other classes, the highest metered demands were assumed to be equal to the coincident demands, and the 12 monthly demands were averaged to determine the class contributions to the annual power supply billing demand.

Naperville collects no demand data for its Residential Rate and Residential Electric Heating Rate classifications. Estimates of the contributions of these groups to the power supply billing demand were developed based on assumptions of appropriate load factors determined from data for other BMC projects and experience. The assumed load factors were applied to the corresponding total energy sales to estimate the coincident demand contributions for these classes.

The system demand costs (other than power supply demand costs) were allocated based on estimates of each rate class's non-coincident peak demand. For all rate classes and customers that were demand metered, the highest recorded demand was used. For the two residential classes, maximum demands were again estimated based on assumed load factors, applied to the corresponding total energy sales.

Ratios of each class's contributions to Naperville's average power supply billing demand and ratios of the maximum non-coincident demands for each class to the total for all classes were calculated. These ratios represented the factors to be used in allocating the power supply demand costs and all other system demand costs among the various rate classes.

Customer Allocation: A customer allocation factor was developed to allocate the costs of customer services among the various rate classifications. The allocation factor was based on relative weighting of the number of customers included in each rate class.

Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to customers in the different rate classes. With the relative weight of a residential customer assumed to be equal to one, the other classes were assigned weighting factors. Any rate class that was assumed to require more effort in meter reading, billing, collection and other customer services as compared to a residential customer was assigned a relative weight greater than one. Likewise, any class that was assumed to require less effort to serve was assigned a factor of less than one. The numbers of customers for each classification were multiplied by the relative weight factor to calculate the weighted number of customers in each class. The ratios of the weighted customer counts for each class to the total weighted number of customers represented the customer allocation factor.

Cost Allocation: Each component item of the adjusted annual revenue requirement, which was previously unbundled to the various functional utility services, was allocated to the appropriate customer classifications using the corresponding allocation factors described above. The allocated amounts were summarized for each rate class, both in dollars and on a cents/kilowatt-hour (kWh) basis. The actual allocation of the unbundled amounts for each of the various components of the adjusted annual revenue requirement is contained within the cost-of-service model developed for Naperville.

Based on the results of the allocation of the adjusted annual revenue requirement to the rate classifications and individual customers included in the cost-of-service analysis, Naperville determined that it was appropriate to combine several of the current classifications and customers analyzed into fewer groups. The proposed changes to the rate classifications included:

- Combination of General Service Rate and General Service Electric Heating Rate classes
- Combination of Large General Service Rate, Educational Institution Rate, and Religious Institution Rate classes

- Combination of Government Rate and Municipal Rate classes

These classifications were separated in previous rate studies because differences in the costs of providing service to them were assumed to differ. However, availability of improved data and information used for this study resulted in the determination that separation of these classes was no longer warranted.

Table 6 presents a summary of the allocation of the adjusted annual revenue requirement to the revised rate classifications by the unbundled functional services. The total amounts in the first column of Table 6 for each unbundled service were carried forward from Table 5. The summary of the allocations to each customer classification is shown on Table 6 for each unbundled service, both in dollars (top section) and in cents/kWh (bottom section). Naperville's adjusted annual revenue requirement of $75,164,160 represents an average cost of 5.72 cents/kWh.

ADJUSTED RATE BASE

The level of net margins included in Naperville's adjusted annual revenue requirement, as indicated previously, was established based on an interest coverage ratio of 3.00 times. Although this target interest coverage was used to determine net margins, Table 1 also included calculations of the projected debt service coverage ratio and the rate of return on rate base as alternative financial performance measurements. In order to present the return on rate base, Naperville's rate base had to be forecast, unbundled, and allocated for the period through FY2004 in a manner similar to that used for the analysis of the adjusted annual revenue requirement.

Rate base includes net utility plant-in-service, plus working capital, minus deductions for funds of others held in reserve (which effectively reduce the total investment in the utility). It is a representation of the total net capital invested in the utility. Table 7 presents a summary of the forecast of Naperville's adjusted rate base for the three-year period FY2002 through FY2004. Utility plant-in-service and accumulated depreciation balances as of the end of each fiscal year were projected as part of the analysis in the development of the depreciation expense forecast described previously. The balances reflected in the last column on Table 7 represent the average balances for the three-year period. The forecast net plant-in-service included in the adjusted rate base was $173,568,424.

The working capital included in rate base represents both an allowance for a portion of annual operations and maintenance expenses and the balance of certain current assets from Naperville's Balance Sheet. The allowance for expenses is based on an assumed time lag between the time Naperville incurs expenses associated with providing utility service and the time it receives revenues to recover those costs. BMC assumed a lag of 45 days, based on a rule of thumb used by some utility commissions that the allowance should equal one-eighth of the annual operating expenses. The amount of the allowance was determined for each fiscal year and the average for the three-year period FY2002 though FY2004 was calculated. The balances in two current asset accounts related to temporary cash investments and inventory were also included in working capital. Since there was no reasonable basis for projecting the future balances of these items, they were included at the FY1999 levels. The total projected working capital for rate base was $13,504,881.

The final component of Naperville's rate base, deductions for funds held for others, was determined from the Balance Sheet. The two deductions from rate base were the amounts for customer deposits and advances for construction. These were deductions from rate base because Naperville effectively had the beneficial use of these funds, even though the funds will ultimately be returned to the customer or developer. Since there was no reasonable basis for projecting the future balances of these items, they were included at the FY1999 levels. The total of the deductions from rate base was $3,593,645.

Total adjusted rate base as shown on Table 7 for the three-year period FY2002 through FY2004 was forecast to be $183,479,660.

Unbundling of Adjusted Rate Base

The various components of rate base were unbundled to the same functional utility services and in a similar manner as was the adjusted annual revenue requirement. However, because Naperville does not own any electric generation assets, none of the rate base was assigned to any of the power supply services. The plant-in-service and accumulated depreciation amounts were unbundled consistently with the manner in which depreciation expense had been assigned. The various expense allowances included in working capital were handled in the same way the actual expenses were treated in the unbundled revenue requirement. The current assets and deductions were assigned to the functional services they most closely impacted. The actual assignment of each item within the three categories making up the rate base is contained within the cost-of-service model prepared for Naperville.

The unbundling of the various components of Naperville's adjusted rate base is summarized on Table 8. The three-year average forecast for net utility plant-in-service, working capital, and deductions for funds held for others shown in the last column on Table 7 were carried forward to Table 8. These amounts are followed by the summary of the assignments to each unbundled functional service. Table 8 shows the total and percentage breakdown of the unbundled rate base assigned to each of the functional services Naperville provides.

Allocation of Adjusted Rate Base

The unbundled adjusted rate base was allocated to Naperville's current customer classifications based on the same allocation factors as were used to allocate the adjusted annual revenue requirement. Each component item of the adjusted rate base, which was previously unbundled to the various functional utility services, was allocated to the appropriate customer classifications using the same allocation factors as were used for the corresponding expenses included in the revenue requirement. The allocated amounts were summarized for each rate class. The actual allocation of the unbundled amounts for each of the various components of the adjusted rate base is contained within the cost-of-service model developed for Naperville.

The top portion of Table 9 presents a summary of the allocation of the adjusted annual revenue requirement to the revised rate classifications by the unbundled functional services. The total amounts in the first column of Table 9 for each unbundled service were carried forward from Table 8. The summary of the allocations to each customer classification is shown on Table 9 for each unbundled service.

The bottom half of Table 9 shows the corresponding allocations of the adjusted total net margins included in the adjusted annual revenue requirement. This facilitates the presentation of the calculated rate of return on rate base for each rate classification. Confirming the adjusted rate of return shown on Table 1, the adjusted net margins of $1,724,771 divided by the adjusted total rate base of $183,479,660, results in a calculated rate of return on rate base of 0.94 percent. Table 9 illustrates that the allocations of the adjusted annual revenue requirement and adjusted rate base reflect an equivalent level of return from each rate classification.

SUMMARY

On Table 10, the results of the cost-of-service analysis are presented. The results are broken down into energy-related costs, expressed in dollars and cents/kWh; demand-related costs, expressed in dollars and dollars per kW of system power supply billing demand per month; and customer-related costs, expressed in dollars per customer per month. Also, the total cost of service is expressed in dollars and cents/kWh.

Table 10 also provides a comparison of the total allocated revenue requirement to the projected revenue to be generated by Naperville's current retail rates. As shown, the projected revenue that would be generated by existing rates, $81,551,039, exceeds the total adjusted annual revenue requirement by $6.386.879, or 7.8 percent. This amount is consistent with the financial performance adjustment reflected on Table 1. Table 10 served as input into the process of considering the revision of the current retail electric rates. The consideration of this data, as well as other factors relating to the design of Naperville's electric rates, is discussed in Part III of this report.

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PART III – RATE DESIGN ANALYSIS

PART III
RATE DESIGN ANALYSIS

OVERVIEW

The unbundled, allocated cost-of-service analysis completed for Naperville by BMC, as described in Part II of this report, served as input to the analysis and design of revised retail rates for Naperville's consideration. Naperville identified the following objectives for this rate study:

- To update retail rates based on changing costs of providing service.
- To ensure full recovery of costs of providing service.
- To adopt current leading edge practices in design of rate alternatives.
- To build and improve upon the rate enhancements achieved with the last retail rate change implemented November 1, 1995.
- To consider the results of previous studies related to the rates charged to Lucent Technologies and to customers having cogeneration facilities.

RATE CLASSIFICATIONS

As was mentioned in Part II, the results of the cost-of-service analysis indicated that combination of certain existing rate classifications was justified. In the rate design analysis, revised rates were developed for the classifications shown in the summary of the cost-of-service analysis on Table 10. The classes for which revised rates were designed include:

- Residential Rate
- Residential Electric Heating Rate
- General Service Rate (50 kW or less)
- Large General Service Rate (including high load factor rate provision)
- Primary Metering Rate (including high load factor rate provision)
- Primary Metering Time-of-Use Rate
- Transmission Metering Rate
- Government Rate
- Municipal Pumping Rate
- Athletic Field Lighting Rate
- Contract Outdoor Lighting Rate

- Metered Outdoor Lighting Rate
- Traffic Lighting Rate

EXISTING RATES

Table 11 presents the current rates applicable to each of the revised rate classifications. The Residential, General Service < 50 kW, Metered Outdoor Lighting, and Traffic Lighting Rates each include a monthly customer charge and a flat energy charge per kWh used. The Residential Electric Heating Rate includes a second energy block with a reduced rate for energy used over 800 kWh applicable for the months of October through May. The contract Outdoor Lighting Rate consists of flat monthly fees for each of various sizes of fixtures. The remaining rate schedules include monthly customer charges, flat demand charges applicable to maximum demand, and flat energy charges. The Large General Service and Primary Metering Rates include provisions of alternate demand charges for customers meeting minimum load and load factor requirements. In addition, the Primary Metering Time-of-Use Rate includes an alternate energy charge structure with different rates for on-peak and off-peak energy usage.

Table 12 shows the average annual revenue projected to be generated by the existing rates for each class for the three-year period FY2002 through FY2004. The projected revenues are shown in the second column, with the breakdown of the adjusted annual revenue requirement by rate classification in the first column, as detailed on Table 10.

RATE DESIGN ANALYSIS

The proposed rate design for each class generally follows the existing rate structure. In the 1995 rate study the rate structures were simplified for understandability and ease of application. The proposed rate design was developed to achieve a balance between Naperville's objectives to base the retail rates on the allocated cost of service, to minimize the impacts of rate changes on each group of customers, and to provide full recovery of the costs of providing service.

Table 11 also lists the proposed rates for each rate class beside the current rates. Table 12 presents the estimated revenues from these proposed rates in the third column and shows the comparison with the projected revenues from existing rates. As shown on Table 12, the proposed rate design would result in total revenues of $75,163,216, an overall decrease in revenues of approximately 7.8 percent.

Following is a description of the proposed rates for each rate classification. For each class, a comparison of monthly bills calculated for varying levels of consumption, including the average use per customer for the class, is provided.

Residential Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Residential classification was projected to be $37,632,746, which exceeded the allocated cost of service by $4,727,734, for the three-year period FY2002 through FY2004. Since the cost-of-service analysis indicated revenue increases were required for several rate classes, despite an overall revenue decrease for the whole system, Naperville decided to limit the amount of the decrease in the Residential Rate. The remainder of the indicated decrease would partially offset the required increases to other rate classes.

The existing Residential Rate consisted of a monthly customer charge of $9.50 and a flat energy charge of 6.62 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would include a reduced monthly customer charge of $6.26 and the energy charge would decrease to 6.14 cents/kWh.

With the proposed customer and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Residential Rate was $33,462,001. As shown on Table 12, this estimated revenue represents a decrease from the projected revenues from the existing rate of $4,170,745, or 11.1 percent.

Table 13 provides sample bill calculations at varying levels of consumption for the Residential Rate. Sample bills are calculated using both the existing and proposed rates. For the Residential class, based on an average monthly consumption of 834 kWh, the proposed rate would generate a monthly bill of $57.47, compared to a bill of $64.71 based on the existing rate. This is a difference of $7.24, or 11.2 percent.

Residential Electric Heating Rate

The Naperville Municipal Code provided a separate rate schedule for Residential Electric Heating. This rate was similar to the Residential Rate, as the customer charge and the base energy charge were identical to those for the Residential Rate. However, the current Residential Electric Heating Rate provided a reduced energy charge of 4.24 cents/kWh during the months of October through May for any energy usage in excess of 800 kWh per month.

Table 12 indicated that annual revenue from existing rates for the Residential Electric Heating classification, $2,339,650, was projected to exceed the allocated cost of service by $210,660, for the three-year period FY2002 through FY2004.

The proposed rate design maintained this separate rate classification for Residential Electric Heating and retained the similarity with the Residential Rate. The proposed customer charge and base energy rate would be $6.26 per month and 6.14 cents/kWh, respectively, which match the charges proposed for the Residential Rate. The proposed rate also provided an energy charge of 4.32 cents/kWh for energy consumption in the non-summer months in excess of 800 kWh per month. The existing cutoff between the base energy rate and the second block rate of 800 kWh was retained in the proposed rate design for the Residential Electric Heating Rate. The rate for the second energy block was increased slightly to better reflect the distribution of energy sales between the two energy blocks.

With the proposed customer and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Residential Electric Heating Rate was $2,128,912. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rate of $210,738, or 9.0 percent.

Table 14 provides sample bill calculations at varying levels of consumption for the Residential Electric Heating Rate. Sample bills are calculated using both the existing and proposed rates. For this class, based on an average monthly consumption of 954 kWh, the proposed rate would generate a monthly bill of $62.03, compared to a bill of $68.99 based on the existing rate. This is a difference of $6.96, or 10.1 percent.

General Service Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the General Service (< 50 kW) classification was projected to be $7,582,328, which would exceed the allocated cost of service by $365,915, for the three-year period FY2002 through FY2004.

The existing General Service Rate consisted of a monthly customer charge of $17.00 and a flat energy charge of 6.83 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would lower the current monthly customer charge to $9.40 and the energy charge would decrease to 6.71 cents/kWh.

With the proposed customer and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the General Service Rate was $7,218,293. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rate of $364,035, or 4.8 percent.

Table 15 provides sample bill calculations at varying levels of consumption for the General Service Rate. Sample bills are calculated using both the existing and proposed rates. For the General Service class, based on an average monthly consumption of 2,789 kWh, the proposed rate would generate a monthly bill of $196.54, compared to a bill of $207.49 based on the existing rate. This is a difference of $10.95, or 5.3 percent.

The Naperville Municipal Code also provided a separate rate schedule for General Service Electric Heating. This rate was similar to the General Service Rate, as the customer charge and the base energy charge were identical to those for the General Service Rate. However, the existing General Service Electric Heating Rate provided a reduced energy charge of 4.00 cents/kWh during the months of October through May for any energy usage in excess of 3,000 kWh per month. However, the cost-of-service analysis completed for Naperville indicated that the prior justification for this separate rate no longer existed. BMC proposed that Naperville eliminate the separate General Service Electric Heating Rate. Customers billed on this rate would be billed on the General Service Rate in the future. This change would be expected to affect approximately 210 customers.

Large General Service Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rates for the Large General Service classification, $21,853,918, was projected to exceed the allocated cost of service by $1,098,690 for the three-year period FY2002 through FY2004.

As was mentioned in Part II of this report, the results of the allocated cost-of-service analysis indicated that the justification for the separate Educational Institution Rate and the separate Religious Institution Rate no longer existed. BMC proposed that Naperville eliminate these separate rates. Customers billed on these rates would be billed on the Large General Service Rate in the future. This change would be expected to affect approximately 44 educational institutional customers and 21 religious institutional customers.

The existing Large General Service Rate consisted of a monthly customer charge of $36.60, a flat demand charge of $7.93/kW of maximum demand, and a flat energy charge of 3.23 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would reduce the current monthly customer charge to $24.00, the demand charge to $7.90/kW and the energy charge to 3.00 cents/kWh.

In 1998, as a result of the addition of a substantial new load to the Naperville system, the City amended the Municipal Code to provide an additional rate alternative as part of the Large General Service Rate. In recognition of the fact that the cost of providing electric service to large and highly efficient customer loads would be significantly lower on a per-unit basis than for most customers, thus reducing the overall system average cost of service, Naperville implemented a discounted rate designed for such loads. The amended rate provided for a reduced demand charge of $7.14, in lieu of the standard Large General Service Rate demand charge of $7.93, for those customers with loads in excess of 3000 kW and an annual load factor of at least 60 percent. The corresponding customer charge and energy rate were the same as for the standard Large General Service Rate.

The proposed new alternative Large General Service Rate for high load factor customers would be based on the same minimum load criteria. It would include a higher customer charge, $48.00, than for the standard Large General Service Rate. The customer charge was higher than the corresponding charge for the standard rate to recover higher costs of the more expensive metering and more complex customer billing requirements. The proposed demand charge on maximum demand and the proposed energy rate would both be lower at $6.64/kW and 2.90 cents/kWh, respectively.

With the proposed standard and alternative rates, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Large General Service Rate was $20,757,942. As shown on Table 12, this revenue represents a decrease of $1,095,976 compared to the projected revenues from the existing rates, a reduction of 5.0 percent.

Table 16 provides sample bill calculations at varying levels of energy consumption and load factors for the standard Large General Service Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 57,143 kWh and an average maximum demand of 156.75 kW, the proposed rate would generate a monthly bill of $2,976.62, compared to a bill of $3,125.35 based on the existing rate. This is a difference of $148.73, or 4.8 percent.

Table 17 provides sample bill calculations at varying levels of energy consumption and load factors for the alternative Large General Service Rate for high load factor customers. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 3,233,656 kWh and an average maximum demand of 6,791.11 kW, the proposed rate would generate a monthly bill of $138,916.99, compared to a bill of $152,972.21 based on the existing rate. This is a difference of $14,055.22, or 9.2 percent.

Primary Metering Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Primary Metering classification, $9,955,761, was projected to fall short of the allocated cost of service by $525,486 for the three-year period FY2002 through FY2004. Although an increase in revenue was indicated for this classification, the proposed rate design was developed such that a slight decrease would result for the Primary Metering class. This was possible due to the limit placed on the amount of the revenue decrease incorporated into the proposed Residential Rate.

The existing Primary Metering Rate consisted of a monthly customer charge of $36.60, a flat demand charge of $6.87/kW of maximum demand, and a flat energy charge of 2.80 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would lower the monthly customer charge to $24.00. The current demand charge of $6.87/kW would be retained; however, the energy charge would increase slightly to 2.88 cents/kWh.

As for the Large General Service Rate, the City amended the Municipal Code in 1998 to provide an additional rate alternative as part of the Primary Metering Rate in recognition of the impact that large and highly efficient customer loads would have on the overall system average cost of service. Naperville implemented a discounted rate designed for such loads that are primary metered. The amended rate provided for a reduced demand charge of $6.18, in lieu of the Primary Metering Rate demand charge of $6.87, for those customers with loads in excess of 5000 kW and an annual load factor of at least 60 percent. The corresponding customer charge and energy rate were the same as for the standard Primary Metering Rate.

The proposed new alternative Primary Metering Rate for high load factor customers would be based on similar minimum load criteria, except that the minimum demand requirement would be reduced from 5000 kW to 3000 kW. It would include a higher customer charge, $48.00, than for the Primary Metering

Rate. However, the proposed demand charge on maximum demand would be lowered to $5.78 and the proposed energy rate would be 2.86 cents/kWh.

With the proposed standard and alternative rates, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Primary Metering Rate as a whole was $9,936,778. As shown on Table 12, this revenue represents an overall decrease from the projected revenues from the existing rates of $18,983, or 0.2 percent.

Table 18 provides sample bill calculations at varying levels of energy consumption and load factors for the standard Primary Metering Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 92,072 kWh and an assumed maximum demand of 213.37 kW, the proposed rate would generate a monthly bill of $4,141.53, compared to a bill of $4,080.47 based on the existing rate. This is a difference of $61.06, or 1.5 percent.

Table 19 provides sample bill calculations at varying levels of energy consumption and load factors for the alternative Primary Metering Rate for high load factor customers. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 3,542,404 kWh and an average maximum demand of 6,706.05 kW, the proposed rate would generate a monthly bill of $140,121.72, compared to a bill of $140,667.30 based on the existing rate. This is a difference of $545.58, or 0.4 percent.

Primary Metering Time-of-Use Rate

The Naperville Municipal Code included a Primary Metering Time-of-Use Rate that provided reduced demand and energy charges compared to those in the Primary Metering Rate. Although this rate had been in effect since 1995, none of Naperville's customers on the Primary Metering Rate had elected to switch to this rate. The primary Metering Time-of-Use Rate was re-evaluated to determine if revisions could be made to make it more attractive to the Primary Metering customers.

The Primary Metering Time-of-Use Rate was intended as an additional rate option for Naperville's large customers and as a load management tool to encourage off-peak electric consumption. The key to implementation of a time-of-use rate is having the required metering installed to capture energy consumption by time of day. It would be best to install time-of-use metering and begin to capture usage data on a time-of-use basis before implementing a time-of-use rate. This would allow for accumulation of historical data on which to base the development of a time-of-use rate.

The existing Primary Metering Time-of-Use Rate was developed based on assumptions as to the percentage breakdown of total energy consumption between on-peak and off-peak periods. A 35%/65% on-peak/off-peak energy split was estimated from analysis of proxy load research data from ComEd. Based on the on-peak and off-peak wholesale energy purchases by Naperville for FY1999 and an analysis of the actual on-peak and off-peak energy use for several of the large Primary Metering customers having interval metering, it was estimated that the split of on-peak and off-peak energy was closer to 43%/57%. Since on-peak energy is more expensive and the percentage of on-peak energy assumed would be increased, revision of the Primary Metering Time-of-Use Rate to reflect this revised energy split would result in a higher average cost of the energy used. However, BMC developed a proposed revision to the Primary Metering Time-of-Use Rate for consistency with the proposed Primary Metering Rate.

The existing Primary Metering Time-of-Use Rate consisted of a monthly customer charge of $50.00, a flat demand charge of $6.87/kW of maximum demand, and flat energy charges of 4.20 cents/kWh for on-peak consumption and 2.02 cents/kWh for off-peak use. The customer charge also was designated as the minimum monthly bill. The proposed new rate would reduce the current monthly customer charge to $48.00. The customer charge was higher than the corresponding charge for the Primary Metering Rate to recover higher costs of the more expensive time-of-use metering and more complex customer billing requirements. Consistent with the Primary Metering Rate, the proposed demand charge would stay at $6.87/kW. The proposed energy charges were 4.54 cents/kWh for on-peak consumption and 2.00 cents/kWh for off-peak use.

Transmission Metering Rate

The Naperville Municipal Code provided for a separate Transmission Metering Rate that included demand and energy charges slightly discounted from those of the Primary Metering Rate. The purpose of this was to compensate any customer taking service at transmission voltage for assuming step-down losses from transformation to primary voltage and transmission level line losses.

The only customer Naperville has had taking service at transmission voltage was BP, one of three customers included in the Cogenerator Service classification. Although the Transmission Metering Rate was applied to supplemental service taken by BP, the nature of the service provided to cogenerators would be significantly different from the service provided to a regular customer. Since there were no regular Transmission Service customers, the results of the cost-of-service analysis did not provide direct quantification of the cost savings to Naperville from customers taking service at transmission voltage.

However, the development of the cost-of-service analysis included consideration of the impact of losses on metered energy and demand for the various rate classifications. System losses totaling approximately 4.11 percent were assumed to occur evenly between transmission voltage, primary distribution voltage, and secondary distribution voltage. The losses at each level were allocated among the classes utilizing that level of the system. Therefore, the rate classes/customers receiving service at transmission voltage or primary voltage were assumed to not share in secondary distribution system losses. Similarly, the customer receiving service at transmission voltage was assumed to not share in the primary distribution losses. Therefore, the difference between providing service at transmission voltage and providing service at primary distribution voltage was the losses attributed to the primary distribution level, or approximately 1.39 percent. This factor was applied to the proposed Primary Metering Rate to determine the appropriate Transmission Metering Rate.

The existing Transmission Metering Rate consisted of a monthly customer charge of $36.60, a flat demand charge of $6.80/kW of maximum demand, and a flat energy charge of 2.77 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would include a monthly customer charge of $48.00. The proposed demand charge would decrease to $6.77; however, the energy charge would increase slightly to 2.84 cents/kWh.

Government Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Government classification, $637,183, was projected to fall short of the allocated cost of service by $27,054 for the three-year period FY2002 through FY2004. Although an increase in revenue was indicated for this classification, the proposed rate design was developed to maintain total revenue from the Government class near the level projected based on the current rates. This was possible due to the decision to limit the amount of the revenue decrease incorporated into the proposed Residential Rate.

As was mentioned in Part II of this report, the results of the allocated cost-of-service analysis indicated that the justification for the separate Municipal Rate no longer existed. BMC proposed that Naperville eliminate this separate rate. Customers billed on this rate would be billed on the Government Rate in the future. This change would be expected to affect approximately 10 customers.

The existing Government Rate consisted of a monthly customer charge of $17.00, a flat demand charge of $9.75/kW of maximum demand, and a flat energy charge of 2.78 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would retain the current monthly customer charge of $17.00. The proposed demand charge would decrease to $9.00; however, the energy charge would increase to 3.00 cents/kWh.

With the proposed customer, demand, and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Government Rate was $638,812. As shown on Table 12, this revenue represents an increase over the projected revenues from the existing rates of $1,629, or 0.3 percent.

Table 20 provides sample bill calculations at varying levels of energy consumption and load factors for the Government Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 48,325 kWh and an average maximum demand of 166.55 kW, the proposed rate would generate a monthly bill of $2,965.70, compared to a bill of $2,984.30 based on the existing rate. This is a difference of $18.60, or 0.6 percent.

Municipal Pumping Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Municipal Pumping classification was projected to be $358,785, which exceeded the allocated cost of service by $85,692 for the three-year period FY2002 through FY2004.

The existing Municipal Pumping Rate consisted of a monthly customer charge of $17.00, a flat demand charge of $9.75/kW of maximum demand, and a flat energy charge of 2.78 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would retain the current monthly customer charge of $17.00. The proposed demand charge would decrease to $5.80; however, the energy charge would increase to 3.00 cents/kWh.

With the proposed customer, demand, and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Municipal Pumping Rate was $274,481. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $84,304, or 23.5 percent.

Table 21 provides sample bill calculations at varying levels of energy consumption and load factors for the Municipal Pumping Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 10,602 kWh and an average maximum demand of 83.82

kW, the proposed rate would generate a monthly bill of $821.22, compared to a bill of $1,128.98 based on the existing rate. This is a difference of $307.76, or 27.3 percent.

Athletic Field Lighting Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Athletic Field Lighting classification, $54,798, was projected to exceed the allocated cost of service by $3,546 for the three-year period FY2002 through FY2004.

The existing Athletic Field Lighting Rate consisted of a monthly customer charge of $17.00, a flat demand charge of $4.75/kW of maximum demand, and a flat energy charge of 2.86 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would retain the current monthly customer charge of $17.00. The proposed demand charge would increase to $5.65; however, the energy charge would decrease to 2.00 cents/kWh.

With the proposed customer, demand, and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Athletic Field Lighting Rate was $51,239. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $3,559, or 6.5 percent.

Table 22 provides sample bill calculations at varying levels of energy consumption and load factors for the Athletic Field Lighting Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 20,489 kWh and an average maximum demand of 152.99 kW, the proposed rate would generate a monthly bill of $1,291.17, compared to a bill of $1,329.69 based on the existing rate. This is a difference of $38.52, or 2.9 percent.

Contract Outdoor Lighting Rates

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Contract Outdoor Lighting classification of $13,380 was projected to exceed the allocated cost of service by $6,001 for the three-year period FY2002 through FY2004.

The current rates charged by Naperville for lighting under customer contracts are flat monthly fees that vary depending on the wattage size of the fixture. Although Naperville had mostly mercury vapor lights during FY1999, the standard installation was changed to high pressure sodium fixtures. The rates in effect for the various sizes of mercury vapor and high pressure sodium lights are listed on Table 11.

Naperville completed an inventory of the lights billed on the Contract Outdoor Lighting Rates and an assessment of the current cost of labor and materials to install each size of fixture. This information was used in conjunction with the results of the cost-of-service analysis to develop proposed new monthly rates. Since the mercury vapor lights were being phased out, the existing rates were maintained. Proposed rates for the high pressure sodium fixtures were as follows: $3.82/Month for 70-Watt lamp, $4.29/Month for 100-Watt lamp, $5.38/Month for 200-Watt lamp, and $7.26/Month for 400-Watt lamp.

With the proposed monthly charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Contract Outdoor Lighting Rates was $7,145. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $6,235, or 46.6 percent.

Metered Outdoor Lighting Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Metered Outdoor Lighting classification was projected to be $19,645, which exceeded the allocated cost of service by $8,793 for the three-year period FY2002 through FY2004.

The existing Metered Outdoor Lighting Rate consisted of a monthly customer charge of $9.50 and a flat energy charge of 5.77 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would reduce the monthly customer charge to $9.40 and the energy charge to 2.00 cents/kWh.

With the proposed customer and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Metered Outdoor Lighting Rate was $10,938. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $8,707, or 44.3 percent.

Table 23 provides sample bill calculations at varying levels of energy consumption for the Metered Outdoor Lighting Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 328 kWh, the proposed rate would generate a monthly bill of $15.96, compared to a bill of $28.43 based on the existing rate. This is a difference of $12.47, or 43.9 percent.

Traffic Lighting Rate

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the existing rate for the Traffic Lighting classification, $99,359, was projected to exceed the allocated cost of service by $19,914 for the three-year period FY2002 through FY2004.
The existing Traffic Lighting Rate consisted of a monthly customer charge of $9.50 and a flat energy charge of 5.77 cents/kWh. The customer charge also was designated as the minimum monthly bill. The proposed new rate would reduce the current monthly customer charge of $9.40 and the energy charge would decrease to 4.51 cents/kWh.

With the proposed customer and energy charges, the estimated average annual revenue for the three-year period FY2002 through FY2004 from the Traffic Lighting Rate was $79,536. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $19,823, or 20.0 percent.

Table 24 provides sample bill calculations at varying levels of energy consumption and load factors for the Traffic Lighting Rate. Sample bills are calculated using both the existing and proposed rates. Based on an average monthly consumption of 1,652 kWh, the proposed rate would generate a monthly bill of $83.91, compared to a bill of $104.82 based on the existing rate. This is a difference of $20.91, or 20.0 percent.

Cogenerator Rates

The summary of the allocated revenue requirement from Table 12 indicated that annual revenue from the Cogenerator customers on Naperville's system was projected to be $1,003,488, exceeding the allocated cost of service by $412,475 for the three-year period FY2002 through FY2004.

There were three customers connected to Naperville's electric system that own cogeneration facilities located on-site: Nalco, BP, and Nicor. Naperville provided supplemental, maintenance, and backup service to each of these customers under separate contractual agreements, which identified the terms and rates applicable to the individual services.

The agreements each included one or more of various customer charges, facility reservation charges, and general administrative charges. Generally, the demand and energy rates charged for maintenance and backup services were tied to the rates at which Naperville purchased its power from ComEd, its wholesale power supplier. Supplemental service provided by Naperville to these customers was billed at the regular rates that would be applicable to the customers absent their cogeneration equipment. As mentioned previously, Supplemental service to BP was billed on Naperville's Transmission Metering Rate. Nalco and Nicor were charged for supplemental service under the Primary Metering Rate and Large General Service Rate, respectively.

In April 2000, BMC completed a review of the rates and charges included in the agreements between Naperville and two of the cogeneration customers, BP and Nalco. In the Report on the Review of Cogeneration Contracts, dated April 4, 2000, BMC proposed several recommendations regarding how the cogeneration customers could be charged for service in the future. However, the development of proposed rates was deferred until the next comprehensive electric rate study. As a result of the completion of this cost-of-service and rate analysis, BMC recommends that Naperville implement individual monthly facilities reservation charges for each cogenerator. These charges would be designed to provide full recovery of the transmission and distribution system facilities, the associated operations and maintenance costs, and administrative costs related to these customers being connected to the Naperville electric system. These facilities charges would also include recovery of net margins allocated to the cogenerator customers. In addition, all actual electric service taken by the cogenerators, regardless of whether identified as supplemental, maintenance, or backup, would be billed at the wholesale power supply rates paid by Naperville for the corresponding month.

BMC proposes monthly facilities reservation charges of $3.88/kW for Nalco (based on an assumed maximum potential demand of 4,076 kW), $1.34/kW for BP (based on an assumed maximum potential demand of 9,169 kW), and 3.19/kW for Nicor (based on an assumed maximum potential demand of 436 kW). These facilities charges would be applied to the designated potential maximum demand, not the actual monthly maximum demand. The charges were developed based on the maximum demands indicated and any significant variance from these assumed levels would affect the overall revenue Naperville would receive from these customers.

The cogenerator customers have been billed based on their maximum monthly demand. The proposal to charge the cogenerators for supplemental, maintenance, and backup service at the same rates Naperville paid for its wholesale power supply was based on the applicable demand charge being assessed on the customer's average demand coincident with Naperville's power supply billing demand.

With the proposed facilities reservation charges and the application of Naperville's wholesale power rates to actual consumption, the estimated average annual revenue for the three-year period FY2002 through

FY2004 from the Cogenerator classification was $597,139. As shown on Table 12, this revenue represents a decrease from the projected revenues from the existing rates of $406,349, or 40.5 percent.

OTHER RATE CONSIDERATIONS

Conjunctive Billing For Demand

When Naperville took over providing electric service to Lucent Technologies' Indian Hill Complex (Lucent) in 1998, it agreed to bill Lucent based on its conjunctive, or aggregate, demand. Although not widely offered by electric utilities, as a result of the use of conjunctive billing for Lucent, Naperville began to consider offering conjunctive billing to other customers having multiple demand meters/locations rather than billing the customers separately for each account or location. The potential implementation of conjunctive billing for demand for other Naperville customers was evaluated as part of the Electric Rate Audit conducted by BMC and documented on pages II-10 through II-14 in the Report on the Electric Rate Audit, dated March 26, 1999.

Conjunctive (aggregate) demand is the measurement of electrical demand that is the sum of the electrical demands recorded instantaneously (coincident with each other) by all meters of a particular customer. This is opposed to the total noncoincident demand, which is a measurement of electrical demand that represents the sum of the highest demand recorded by each meter regardless of when it occurred. By nature, a customer's highest conjunctive demand would be less than the total noncoincident demand and, therefore, would result in lower demand charges on the customer's monthly bill.

Naperville's primary objective for considering implementation of conjunctive demand billing would be to enhance the services offered to its customers. However, conjunctive billing for demand would require the installation of more expensive meters and would add meter reading and monthly billing costs for Naperville, unless these added costs were passed on to the customer. It also would result in a decrease in revenue, as the number of monthly units of billing demand would decrease due to the switch from noncoincident to conjunctive demand.

The evaluation of conjunctive billing performed as part of the Electric Rate Audit considered many aspects of the implementation of this billing option. The capability of the City's billing system for using the conjunctive demand for billing purposes was verified with the Naperville Finance Department. Analysis of customer loads and meter locations using different criteria for eligibility for conjunctive billing indicated that a range of 20 to 50 customers would be included.

Based on this analysis, Naperville has concluded that it will offer conjunctive billing to customers who meet the following criteria:

1.	Minimum Monthly Maximum Conjunctive Demand	500 kW	<u>or</u>
2.	Minimum Monthly Maximum Conjunctive Demand	300 kW	<u>and</u>
	Minimum Separate Meter Locations for Demand	3	

However, since this is an innovative approach to customer billing, implementation of conjunctive demand billing for any customer will be contingent on that customer agreeing to pay all costs associated with the required interval metering equipment.

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PART IV – SUMMARY AND RECOMMENDATIONS

PART IV
SUMMARY AND RECOMMENDATIONS

SUMMARY

BMC has completed its analysis and development of the Electric Rate Study performed for the City and for Naperville. The study included the development of the cost-of-service analysis. This analysis consisted of development of the adjusted annual revenue requirement based on forecasted revenues and expenses for the three-year period FY2002 through FY2004, the unbundling of the adjusted revenue requirement to separate functional services, and the allocation of the adjusted revenue requirement to re-defined customer rate classifications. The results of the cost-of-service analysis were used as input to the revision of the retail rates. The rate design analysis also included consideration of the customer impacts of the rate changes proposed.

The adjusted annual revenue requirement for Naperville for the three-year period FY2002 through FY2004 was projected to be $75,164,160 on total energy sales of approximately 1,315,096 MWh. Compared to the adjusted annual electric rate revenue under current rates of $81,551,039, the annual revenue requirement reflects a variance of $6,386,879. Estimated revenues expected to be produced by the proposed rates over the three-year period total $75,163,216, representing a decrease of $6,387,825, or 7.8 percent.

BMC reached the following conclusions as a result of the analysis performed:

1. Naperville continues to generate high annual margins and positive financial results.
2. Naperville continues to experience high levels of growth in customers, energy sales, and revenues.
3. Naperville continues to obtain wholesale power at competitive costs.
4. Naperville continues to depreciate fixed assets at rates that appear reasonable compared to other public power systems.
5. Naperville now recognizes contributed capital as Other Operating Revenue in accordance with the requirements of GASB Statement No. 33.

RECOMMENDATIONS

BMC recommends the following:

1. Naperville should consider the proposed retail rates set forth in Part III for implementation, to be effective for fiscal year 2001-2002.
2. Naperville should eliminate the current General Service Electric Heating Rate and transfer the associated customers to the General Service Rate (would affect approximately 210 customers).
3. Naperville should eliminate the current Educational Institution Rate and the Religious Institution Rate and transfer the associated customers to the Large General Service Rate (would affect approximately 44 and 21 customers, respectively).
4. Naperville should eliminate the current Municipal Rate and transfer the associated customers to the Government Rate (would affect approximately 10 customers).
5. Naperville should revise the minimum required load for eligibility for the Primary Metering High Load Factor Rate from 5000 kW to 3000 kW (would affect approximately 3 customers).
6. Naperville should evaluate and update the existing agreements with its customers owning cogeneration equipment.
7. Naperville should offer conjunctive billing for demand by customers having multiple locations.
8. Naperville should implement additional project numbers for capturing operating and maintenance expenses on a functional basis to enhance the cost information available for future rate studies.
9. Naperville should establish a periodic review for the assignment of non-residential customers to the appropriate rate classification.
10. Naperville should implement a load research program and install interval demand recording devices on a statistically valid sample of customers in all rate classes.
11. Naperville should continue to monitor developments relating to the restructuring of the electric utility industry on both national and state levels.

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APPENDIX A – FIGURES

Flow Diagram of Cost-of-Service Process

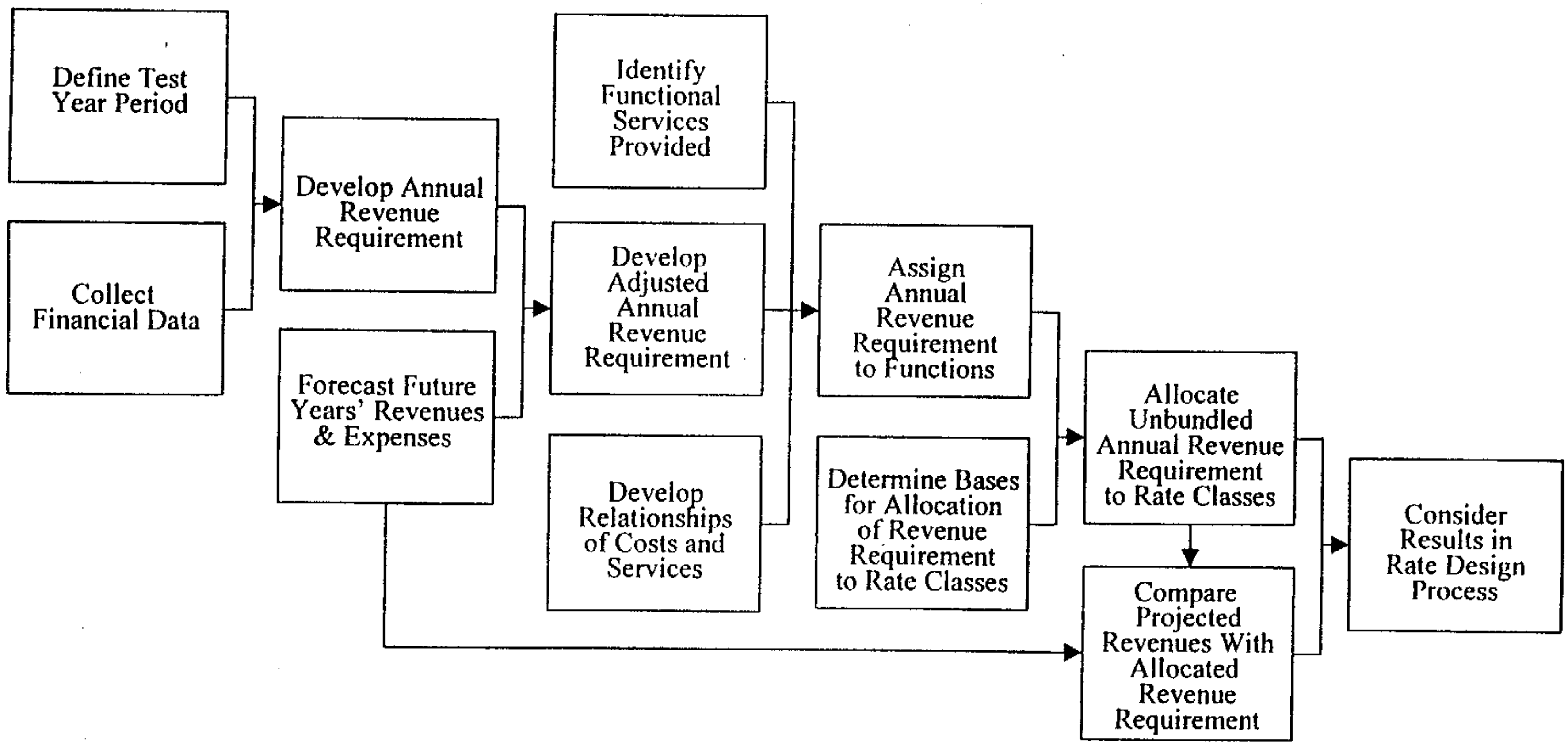

Figure 1